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EA Field Development: Intelligent Well Completion, Offshore Nigeria

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Abstract

Oil and gas reservoirs have traditionally been produced differently mainly due to fear of downhole crossflow and inability to properly allocate production to individual producing reservoirs. As a result, marginal reserves with small hydrocarbon accumulations have generally been left untapped due to economic considerations of developing such accumulations with single or multilateral wells. In the recent past, intelligent well technology has made it possible to produce such reserves commingled through a single wellbore whilst still retaining full control of each individual zone 'remotely' from surface and properly allocating production to each zone. Traditional barriers to general industry acceptance of intelligent well technology have been cost, reliability, and integrated functionality; but, over the past decade, the number of operators that have started to recognize the value potential of intelligent wells has grown. The evolution of intelligent well technology that can now address initial barriers and user perceptions is responsible for this increasing acceptance.

An offshore completion recently installed for Shell Nigeria illustrates how technology selection, development, along with operational excellence in planning and installation can lead to successful deployment of an intelligent well system. This paper discusses the challenges, benefits delivered and the lessons learned during the successful application of intelligent well technology in the EA field.

Introduction

Intelligent well adoption is spreading worldwide, and use has grown steadily over the past ten years as oilfield operators have come to recognize the value potential of this technology. Intelligent well systems have evolved to the point where they can now address some of operators' initial fundamental adoption barriers and user perceptions: i.e. cost, reliability and integrated functionality. Selection of the correct system and operational excellence in planning and installation are key to overcoming the obstacles, real or perceived, that suppliers and operators have faced throughout the evolution of this technology.

A simple, reliable intelligent completion (IC) system was recently installed for a major operator offshore west Africa. This deployment demonstrates how correct technology selection and development, solid planning, and careful execution must be present for successful installation of an intelligent well system.

The EA field is located 15 km South West off the mouth of the Dodo River and about 90km SW of Warri. The field lies in 13 to 25 metres of water in Shell Petroleum Development Company of Nigeria Limited's (SPDC's) Offshore OML-79. The field was discovered in 1965 and consists of a highly faulted and elongated rollover anticline, bounded to the north by a regional growth fault. A total of 101 reservoirs in some 11 fault blocks were encountered at depths between 2,400 and 10,200 ftss with hydrocarbon column ranging from 20ft to 200 ft. Since discovery in 1965 by exploration well EA-1, 17 appraisal wells have been drilled in three successive campaigns to delineate the field's hydrocarbon accumulations. The nearby EJA field was discovered in 1968 and appraised by 5 wells.

The EA/EJA Field Development Plan (FDP) phased this development into two modules, Phase-I and II. During the first phase, 2 EA and 1 EJA drilling platforms were installed from which produced oil and gas are piped into a Floating Production Storage and Offloading (FPSO) facility for processing, storage and discharge into awaiting tankers. The gas is exported from the FPSO to the onshore Nigeria Liquified Natural Gas (NLNG) via the Offshore Gas Gathering System (OGGS) pipeline. A total of 31 EA and 2 EJA development wells and 2 EA appraisal wells were also drilled in a drilling campaign which started in May 2001 and ended in December 2003. A review of the current development is planned before the phase-II development takes off in a few years time.

The reservoirs in the field are characterized by strong aquifer support. Crude characteristics range from 20 API (10-12 cP) in the shallower B sands to 42 API (ca. 0.05 cP) in the deeper F sands. The pressure regime is mostly hydrostatic (0.4245-0.45 psi/ft) with a couple of deep reservoirs showing overpressures (0.485 & 0.593 psi/ft). Phase-I mainly developed the major oil reservoirs. EA field came into production in December 2002 after commissioning of the Sea Eagle FPSO. EA/EJA fields currently produce some 135,000 bopd and 75 MMscf/d.

Objectives and Requirements

The major driver for installation of an intelligent completion is to maximise returns from reservoirs using minimal investment. It is envisaged that successful application of this technology in the EA field development will be an enabler to future commingled production.

The project aims to achieve the following objectives:

- Produce three marginal reservoirs through a single wellbore rather than three independent wells and thereby demonstrate that such reservoirs with low Developed Ultimate Recovery (DUR) that cannot be drained economically with conventional single or multiple string completions (will likely remain undeveloped) can be economically put into production whilst accelerating the Ultimate Recovery (UR) of the field.
- Allocate and manage production of fluids from each zone without need for well intervention thereby saving re-completion and BHP (Bottom Hole Pressure) acquisition costs as well as the avoiding risks associated with implementing such activities offshore.
- Gain experience from implementation of the Smart Well Technology during the phase-1 EA field development for use during the planning and implementation of future developments in EA phase-2 and other fields.
- Reduce the total number of development wells required to fully develop EA and other fields by producing some reservoirs commingled.

The intelligent completion is to be installed in a well completed on an unmanned satellite platform. Control actuation of the well and data acquisition and storage would be managed from the Sea Eagle FPSO, located some 3.5 km (2.2 miles) away. Requirements for the intelligent well system included:

- independent zonal production flow control from the platform and a central location.
- continuous pressure and temperature data acquisition from each zone.
- deliver this data to a central control location.
- single-string multizone completion.
- single-trip completion installation with accurate depth correlation.
- completion to be installed in a 7-inch slotted and blank liner assembly.
- completion to straddle a 7-inch. liner hanger system set in
- a 9 5/8-in. ch production casing.
- simple completion pulling at end of well life.
- scaleable control system architecture.
- operation from remote FPSO location, using a subsea umbilical.
- minimized requirement for wellhead penetrations.
- good system reliability.

Time and budgetary constraints presented the main challenges. The system had to be safely and reliably installed with less than six months of lead time and within a very tight budget.

Candidate Selection

The selection of the candidate reservoirs was guided by the following considerations:

- well must be able to access two or more reservoirs
- reservoirs will have similar pressure gradient
- reservoirs will have similar hydrocarbon type
- reservoirs should be relatively small and undeveloped
- the project should be economically viable (enough producible reserves to guarantee payback)
- reservoirs should have enough drive to flow naturally

To this end, a multi-discipline review of the EA field selected three reservoirs, E8000E, F1000E and F3000E as candidates for an intelligent completion project in one well. Pressure gradients in these reservoirs are hydrostatic, crude is light (ca. 42 API) and Rsi/GOR ca. 1100 scf/bbl. The selected reservoirs are expected to sustain natural flow at over 70% BSW.

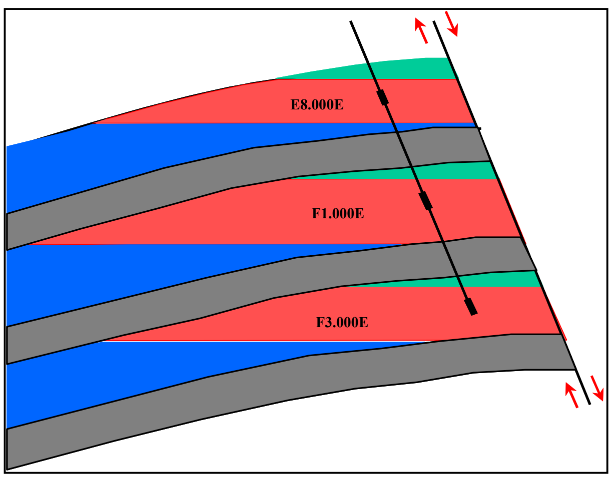


Fig. 1: Schematic cross-section of the 3 reservoirs completed on EA-54

System Selection

After a review of available options, a combined optical-hydraulic technology platform was selected as the most appropriate choice for this application, citing the following reasons:

- simple, cost-effective system with "staircase" approach to new technology introduction
- no downhole electronics
- single-trip installation with minimal intervention during completion running
- simple wellhead interface
- timely delivery schedule
- scaleable surface data acquisition system
- minimal contingency intervention tool requirement
- simple chemical cut/shift to release completion pulling at end of well life

The technology platforms selected were simple hydraulic flow controls and highly reliable, highly sensitive optical sensors. Both components were chosen for their suitability to spawn simple modular intelligent well systems displaying high reliability at an acceptable cost. These decision factors helped successfully balance risks and benefits to comfortably commit to an intelligent well installation. In making this commitment, the following benefits are expected:

- no requirement for intervention to manipulate in-well flow controls
- real-time well testing on selected zones
- nearly instantaneous reaction time for remediation
- no production loss associated with flow control manipulation
- elimination of health, safety, and environmental risks with the absence of a requirement for personnel to be on the platform to manipulate in-well flow controls or acquire data

Planning

Dedicated application of detailed engineering, due diligence and operational planning are major factors affecting the outcome of an intelligent well deployment.

Application Engineering. An important step in achieving the project objectives was undertaking detailed application engineering before installation. The engineering effort ensured that components were environmentally compatible with the reservoir conditions and could be assembled and properly deployed while interfacing with the casing and liner already installed. Tasks included tubing stress analysis; confirmation of material compatibility, pressure and temperature ratings, and geometric eccentricities; control-line routing; cross-coupling clamp placement; subassembly makeup; and determination of internal and external drifting before the manufacturing process.

Pre-Shipment Testing. Another vital step taken to ensure that all the components to be installed do function as specified was the undertaking of Factory Acceptance Tests (FATs). For the FATs, the operator visited the manufacturing site of the suppliers during which all the downhole components to be installed were tested to agreed levels of temperature, pressure and functionality. This activity was carried out before the components were shipped to the operator's country base.

Installation Planning. Installation issues can contribute to the failure of intelligent well and permanent monitoring systems. Thus considerable operational planning went into achieving success in this installation. Development of installation procedures was critical. As an example, one important consideration in procedure development was identification of where surface components such as spooling units and sheaves, a temporary portable hydraulic unit, and a fiber-optic installation unit would be placed during completion equipment deployment.

One of the most valuable planning strategies involved complete-the-well-on-paper (CWOP) and hazard identification (HAZID) exercises. All stakeholders in the system, operator, system supplier and several other service providers, participated in these activities, rehearsing the procedures step by step to identify potential system deployment issues. Communication among all stakeholders at this stage identified critical contingencies that could be applied during event sequence problems or equipment failure.

System Components

An intelligent well consists of in-well and surface systems. The in-well system (Fig. 2) has two core components: hydraulic flow control and optical sensors. At the surface, two independent systems are required: one for optical data acquisition and one for actuation of the hydraulic flow controls (Fig. 3).

Flow Control. The in-well flow control system had to operate the three zones of the well independently, without intervention. Within each zone, a Remotely Operated Sliding Sleeve (ROSS™) would be selectively actuated from surface. The ROSS (Fig. 4) is a simple hydraulic on/off sleeve that uses metal-to-metal and non-elastomeric sealing technology to ensure reliability. Movement of the sleeve is accomplished with a balanced hydraulic piston.

The requirement to install three ROSS sleeves resulted in the number of hydraulic control lines to surface exceeding the available wellhead penetrations; but inclusion of a hydraulically controlled addressing unit (HCAU) immediately below the upper 9 5/8" production packer would reduce the number of hydraulic lines from the surface while allowing independent operation of the three zonal valves.

The HCAU (Fig. 5) is a simple switching control that requires only two hydraulic lines from the surface to operate up to four valves below it. With this capability, only two hydraulic lines would have to be run from the tubing hanger to the first producing zone, which would ensure a sufficient number of wellhead penetrations for all the hydraulic and optical lines required. From this point down, two hydraulic lines would be run to each producing zone's ROSS. This well architecture would also result in a reduction in costs associated with control line supply and rig time to install.

Optical Sensors. The requirement to acquire reservoir parameters was addressed by including a pressure-temperature (P/T) Permanent Downhole Gauge (PDHG) (Fig. 6) at each production zone. Optical P/T gauges were selected because they have no moving parts and because, compared to the electronic equivalent, they have a significantly reduced component count. Both advantages contribute to long-term reliability and stability.

The optical P/T system would have minimal effect on the completion architecture. A gauge mandrel would be run above the ROSS in each zone to mount the low-profile optical sensor. A single optical cable bundle would facilitate interrogation of the gauges. At the surface, an optical wellhead outlet (OWHO) would port the cable through the wellhead to a Reservoir Monitoring System (RMS).

Optical Surface Data Acquisition System. The RMS houses the opto-electronics that interrogate the in-well P/T gauges. This unit would be located on the unmanned satellite platform. It contains an optical source that would transmit light by the in-well cable to the P/T sensors. An optical signal would be reflected from the sensors, along the same in-well cable, back to the RMS system. The system would measure the wavelength of this reflected signal. An onboard computer would then convert this wavelength into the output measurement parameters of pressure and temperature. Changes in reflected wavelength would then equate to changes in measurement parameter.

The permanent monitoring data generated by the RMS on the unmanned platform would be communicated to the FPSO by an ethernet link. Here the data would be archived for future reservoir analysis and further transmitted onshore by the operator for real-time monitoring in the operator's offices. A monitor would also be located on the FPSO to display real-time temperature and pressure data from the three producing zones. The monitor would be connected to the unmanned satellite platoform through the same ethernet communication umbilical and modems as the hydraulic controls.

Hydraulic Surface Control System. The hydraulic switching unit and sliding sleeves would be controlled from the FPSO using an operator interface controller (OIC). The OIC is a touch-screen monitor that communicates with a processor on the unmanned platform containing the logic software for the system. Signals between the OIC and processor would be communicated to and from the unmanned platform by the ethernet umbilical connection.

Inputs to the OIC would control a hydraulic power unit (HPU) on the unmanned platform. The HPU would contain the solenoid valves, pumps, accumulator, fluid filtration, hydraulic oil reservoirs, and electronics required to operate the hydraulic supply system for the in-well flow controls. Sensors included in the HPU would provide feedback to the operator on the FPSO, including information about HPU events such as low fluid levels, equipment tampering, manual operation at the HPU, and successful in-well tool actuation.

Packers. Two 7" and one 9-5/8" Hellcat packers were installed. These are Intelligent completion, hydraulically set, double grip retrivable production packers. The 7" intermediate packers are pull to release while the 9-5/8" packer requires chemical cutting of its inner mandrel to release. All the packers feature a large ID primary bore and multiple control line feed through openings to accommodate the communication links (figure 7). The packers are suitable for HPHT environment (300 deg F and 7500 psi differenctial pressure). Fittings with Metal To Metal (MTM) seals are used for connecting the hydraulic lines to the downhole tools. To eliminate the risk of damage and possible leakage on the connections, compression or tension set packers cannot be used. Therefore hydraulic set packer design was chosen.

Flat Packs. The hydraulic communication link from surface to the hydraulic components are housed in one flat pack containing two hydraulic conduits encapsulated in a plastic material compatible with the annular fluid (figure 8). Similarly, the fibre optic communication links is housed in one flat pack containing the three fibre optic instruction wires encapsulated in a plastic material compatible with the annular fluid (figure 9). The downhole components do not require electrical power. The fibre optic link transmits light signals to and from the downhole gauges whilst the hydraulic line provides, through pressure, the force necessary to operate completion tools.

Below the HCAU, one hydraulic flat pack is used for each with ROSS. Further protection is provided for the flat pack across the producing zones by embedding it special groves recessed into the various IC components (ROSS, Packers, etc). At couplings/ tubing upsets the flat packs are held in place by specially designed cross coupling protection clamps.

Hydraulic Jam Nut Fittings. This fitting is a high performance, externally testable, slim line, double ferrule, metal to metal sealed connector for use with standard hydraulic control lines. The connector is constructed from nickel alloy 718 to match the metallurgy of the control line. See Figure 10.

Tubulars. The well is completed with 3 ½" 9.3 lbs/ft Hydril 533 N80 tubings and carbon steel blast joints for the completion string The choice of 3 ½" tubing is to ensure that individual zones are able to produce through the string, even at later life when water is expected. It allows individual zones to be tested independently and enables production allocation when the zones are produced commingled. All the tubings and components are premium threaded.

Wellhead. The Kvaerner 4 ½" SES single block 5000 psi christmas tree was installed. The seal flange and tubing hanger are designed with six feed through openings to accommodate the hydraulic (downhole valves and TRSCSSSV) and fibre optic communication links. A special tubing hanger running tool allows wrapping of the control lines round the tool while running.

Well Design

The control system chosen for the EA project is a three level Weatherford intelligent completion. The design includes for each zone: One ROSS equipped with one set of pressure and temperature gauges, one isolation packer and blast joints specially designed to fully cover the electro-hydraulic communication link (Flat Pack) in front of perforations. One 3-½" sliding sleeve XD SSD is positioned above the topmost production packer to allow displacement of tubular and annular fluid when necessary. On/off flow control with pressure and temperature feedback to surface is available through a hydraulic communication link. One TRSCSSV is set below surface for safety.

Production Estimation and Allocation

Production estimation is the quantification of mass or volume flow of fluids from each zone, layer or reservoir into the intelligent well. This is different from flow allocation, which is the division of a total mass or volume measurement of fluids into shares representing the contribution of each zone, layer or reservoir. Both production estimation and allocation are important in an intelligent commingled well for reservoir management and production accounting.

Intelligent well technology in a commingled well provides the means to manipulate downhole valves and acquire data required for produced fluids estimation and allocation to individual zones. In the EA case, this will be achieved primarily by periodic testing and determination of the inflow performance relationship (IPR) of each producing interval. This entails:

- conducting individual tests of each zone at the desired rate(s) and calculating PI, water cut GOR.
- conducting commingled flow tests at desired rate(s) and calculating the *un-reconciled* zonal commingled gross, oil, water and gas flow rates for each zone and the reconciliation factors for oil, water and gas.
- carrying out zonal flow allocation calculation using data from the individual test, commingled flow test and actual FBHP (Flowing Bottom Hole Pressure) for each zone.
- under normal commingled producing conditions, using zone flow allocation calculation procedures and the reconciliation factors for oil, water and gas for zonal flow allocation.

The procedures described above are accurate as long as the watercuts of the zones are low and the flowing bottom hole pressures are above bubble point. Once the reservoir pressure of zones fall below bubble point then a different type of inflow model will have to be used.

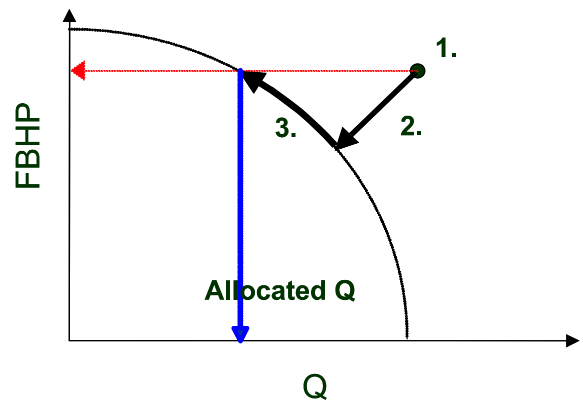
Periodic testing, production estimation and allocation can also be carried out by testing each zone at the FBHP's encountered when all zones are flowed comminlgled. This entails the following steps;

Step-1: FBHP is determined for all zones with PDHG's while the well is flowing from all commingled zones.

Step-2: Close-in Zones-2 and -3 using the surface controlled ROSS. The effect is a reduction in FBHP (Zone-1 flowing alone on the same surface choke size). Meanwhile, obtain pressure build-up data from the closed-in zones.

Step-3: Increase the FBHP to the same value determined for Zone-1 from the PDHGs in Step-1 by adjusting the surface choke and increasing FTHP. The resultant surface flow is the same as the component of the commingled production from Zone-1.

Step-4: Open Zone-2 using the surface controlled ROSS, and close Zone-1. Repeat Step-3 for Zone-2, thus determining the allocation from Zone-2.



Step-5: Zone-3 contribution can be calculated simply by the difference between the total and contributions from Zone-1 and Zone-2 or repeating Step-3.

Test frequency will be depend on well behaviour. In the EA case, the periodic testing technique will be supported by geo-chemical fingerprinting (constituent mass balance).

System Installation

Before the intelligent well system components were shipped to the well site, a site integration test (SIT) was conducted by the supplier along with the operator to ensure that all the components correctly interfaced with each other and with external systems. This involved assembling all the downhole components, including the reels of hydraulic and fibre optic cables as well as surface control components. A stack-up test (including pressure tests) was carried out to ensure compatibility of the system components (OWHO, hydaulic and fibre optic control lines), the wellhead, tubing hanger and tubing hanger running tool. The components were subsequently shipped offshore. The SIT process was repeated offshore.

Careful consideration was given to the subassembly rationale to ensure ease of handling in transit, during unloading, and on the rig floor and to minimize rig time to install. The completion design from the toe of the well to the tubing hanger consisted of 15 subassemblies, as shown in Table 1.

In total, six days were spent running the completion, from picking up the first subassembly to reaching the tubing hanger. Despite some additional time being taken to change out the top packer due to a fibre optic connector damage, splice, terminate and test hydraulic control lines and to connect and test fibre-optic cables, this time was well within planned estimates.

One major operational issue did result in some unplanned rig time. During the space-out procedure, a dogleg immediately above the 7-in. liner is thought to have caused the assembly to hang up, most probably at the no-go sub. While the possibility of this event had been recognized in the planning phase, the location of the string at hangup was exactly where the completion was to be set. After careful deliberation it was agreed that the contingency for such an event would be to set the packers and then “stretch” the tubing to allow installation of the hanger. The contingency solution was successful, and the tubing hanger landed.

Installations of the surface equipment for the hydraulic controls and the optical data acquisition system were also successful. During commissioning of these systems, the electronics section of the HPU had to be relocated. The electronics were repositioned on the top deck of the platform, away from a Zone 2 work area, by co-locating the HPU electronics with the optical sensing RMS system due to zone certification issues.

During the initial well test operations, relocation of the HPU electronics had yet to be completed; but, by using a temporary hydraulic control panel that formed part of the installation equipment, well test operations were successfully completed. The well tests were the final step in confirming the operation of the intelligent well system and the installation a success.

EA-54 Intelligent Well. EA-54 was completed as an intelligent, three zone sand controlled well, employing fiber optic gauges for reservoir monitoring, Swell Packers for zonal isolation and has potential for commingled production. It is the world’s first intelligent well where three new technologies (Swell Packers, fibre optic gauges and down hole hydraulics) were brought together and installed in a sand controlled environment.

The well was drilled to a TD of 9261 MD (Measured Depth), encountering three target reservoirs (E8.000E, F1.000E & F3.000E) at a 77 degree inclination. During this process, the well was sidetracked by milling through the 9 5/8” casing and drilling a new 8 ½” hole updip. Thereafter, a 7” slotted liner along with the 8 swell packers was installed through the milled window at an angle of 70 degrees. Zonal isolation between the reservoirs was achieved with the eight 8.15” OD swell packers in an 8 ½” OH while the 7” slotted liner (0.012” slots, 300 slots/ft) provided some level of sand control. These formed the lower completion.

After installing the lower completion, the rig was then programmed to cleanup and flowback two previously completed wells. This allowed time for the completion tubulars to be measured/inspected/numbered and a tally made up on land. Once this was completed, the fibre optic lines were cut and the connectors welded. This process took four working days (including transport to the rig). Separating the rig operations between the lower completions and installation of the IC system allowed for the fibre connectors and lines to be precut and welded off the critical path. The fibre optics system (reels+gauges) was SIT’ed on the rig prior to installation.

The installation of the IC system was simplified with discrete tested subassemblies. It required the use of three separate ROSS’s, three fibre optics gauges for reservoir monitoring and three zonal/production isolation packers. Multi Control Line Running System (MCLRS) was used. This tubular running system allowed the control line to be run without ever coming in contact with tubing slips. The system is a simple false rotary table where the control lines are run under the false rotary table while the tubing is made up above it. The IC system was landed and tested in November 2003. Figure 11 shows some rig activities during the EA-54 Smart Well Completion installation.

The three zones of EA-54 were independently flowed clean and tested in December 2003. During this process, the zones were opened and closed successfully using the ROSS’s whilst downhole pressure and temperature data was acquired. The pressure data acquired at that time and subsequently shows that the Swell Packers provide good hydraulic pressure isolation between the three reservoirs. Further well tests are planned. Meanwhile, Commissioning of the surface control system is currently in progress.

The well has been producing from one zone since completion. Discussions are at advanced stages with the DPR (Department of Petroleum Resources) to approve a commingled well test and longterm commingled production. If longterm commingled production is approved, the EA well, along with other intelligent completions such as the Nigerian Agip Oil Company (NAOC) completions (ref. 1), will serve as a good test case that can be used to demonstrate the case for commingled production from intelligent wells in Nigeria.

Lessons Learned

Apart from the difficulty encountered while trying to land the string, no other significant negative events marked this installation, but lessons were learned. The primary lesson was that, with rigorous equipment design, diligent application engineering, and careful operational planning and team work, a combined hydraulic flow control-optical sensing intelligent well system can be installed right the first time, safely, and within budget. Several other important lessons were learned as well.

- The need to prepare the wellhead and hanger with extra penetrations required for the hydraulic lines and fibre optic cables are re-emphasised.
- It is essential to fully challenge installation process at CWOP and ensure that all stakeholder involved in the installation are aware of their responsibilities.
- Early involvement of all stakeholders including contractors, subsurface and surface engineers are essential to avoid the need for late re-design work and quick-fixes along with their associated risks.
- Advanced planning did reduce overall system cost (carry out work offline – onshore & offshore).
  - tubing string was pre-measured onshore and tally agreed before mobilizing them to the rig.
  - prior to mobilisation, optical fibres and control lines were cut to required lengths, optical welds (ca. 8 hrs/weld) and control line splices carried out at Weatherford yard, onshore Port Harcourt saving time.
- All critical back-up equipment such as packers, ROSS's and filter/hydraulic pump should be identified ahead of time and made available on location.
- Color coding of inter-zonal control lines will eliminate confusion during installation.
- Specialized expertise is required for success
  - Control, automation and communication
  - Completions
  - Fiber Optic
- Early certification of zone rated surface equipment is essential to avoid unnecessary delays and equipment re-location.
- Hydraulic packers set with control lines should be considered to enable setting by hydraulic control lines as opposed to pump pressure. Control line pressure can easily verify fluid volume and pressure taken to set each packer. This will improve the confirmation of packer setting, especially the interzonal packers.
- Hydraulic packers should be designed to allow circulation so as to avoid the possibility of prematurely setting the packers if circulation is required.

Good communication between all system stakeholders was a critical success factor during this project. Everyone understood, agreed to, and documented the system requirements, interface definitions, well environments, delivery requirement, tool functionality, and control architecture. The CWOP and HAZID exercises proved invaluable in minimizing the potential for operationally interruptive events and ensured contingencies.

The various factory acceptance tests (FATs) of the IC performed after equipment manufacture and witnessed by a Shell representative, facilitated ownership and familiarity by all stakeholders. The SIT provided final confirmation of system readiness before installation offshore.

Conclusions

The EA-54 IC installation took a total eight days, which within planned estimates. Production tests were carried out on each of the zones after the installation during which the functionality and control of the well by the IC were verified. Downhole P/T data acquired during these tests showed that the Swell Packers were isolating the reservoirs. The well was manually controlled from the platform during the tests. Commissioning of the surface equipment that will allow control from the FPSO is currently in progress.

The well has been producing from one zone since completion while awaiting DPR approval for a commingled well test and longterm commingled production. Although it is too early to appreciate the full economical benefit of this completion, this project remains a technical success, opening the door to real time reservoir management. If longterm commingled production is approved, this well will serve as a good test case to demonstrate the case for commingled production from intelligent wells in Nigeria.

Though intelligent well systems may appear complex and somewhat daunting, this case has demonstrated that a successful installation and reliable operation can be achieved with the right technology and a well thought-out completion design and installation plan. Today, the combination of fit-for-purpose completion equipment, good system design and application engineering, and best operational practices makes intelligent well technology a viable completion option.

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Table 1
Subassemblies of an Offshore West Africa Intelligent Well Completion System

No.	Components	Function
1	• Fluted centralizer • Bullnose/bull plug	Ensure ease of entry into the 7-in. line top.
2	• Fluted centralizer above four 3 1/2- x 20-in. blast joints	Protect and centralize the string as it enters and drifts the 7-in. liner.
3	• Remotely Operated Sliding Sleeve • Gauge mandrel • Isolation packer • Splice sub	Provide flow control and data acquisition for deepest producing zone.
4	• Blast joints	Placed across lower producing interval to maintain mechanical properties within the tubing string, accounting for any erosion from the inflow sections of the lower interval.
5	• Orientation sub	Facilitate alignment of Subassembly 6 with the control lines running from the spooling units.
6	• Remotely Operated Sliding Sleeve • Gauge mandrel • Splice sub • Isolation packer • Splice sub	Provide flow control and data acquisition for middle producing zone.
7	• Blast joints	Placed across middle producing interval to maintain mechanical properties within the tubing string, accounting for any erosion from the inflow sections of the middle interval.
8	• Orientation sub	Facilitate alignment of Subassembly 9 with the control lines running from the spooling units.
9	• Remotely Operated Sliding Sleeve • Gauge mandrel	Provide flow control and data acquisition for upper producing zone.
10	• Orientation sub	Facilitate alignment of Subassembly 11 with the control lines running from the spooling units.
	• Fluted no-go centralizer	Tag the 7-in. liner to ensure accurate space-out of equipment.
11	• Hydraulically controlled addressing unit	Allows only two hydraulic lines to be run to surface.
	• Locator sub • Splice sub • 9 5/8-in. production packer • Splice sub	
12	• Landing nipple • Mechanical sliding sleeve	Enables displacement of well to initiate production.
13	• Gas lift mandrel	Provides artificial lift by the preferred method.
14	• Tubing-retrievable surface-controlled subsurface safety valve (TRSCSSV)	Production safety valve for well control in the unlikely event control of the well is lost at surface.
15	• Tubing hanger	Provides wellhead interface and porting of hydraulic control and optical line.

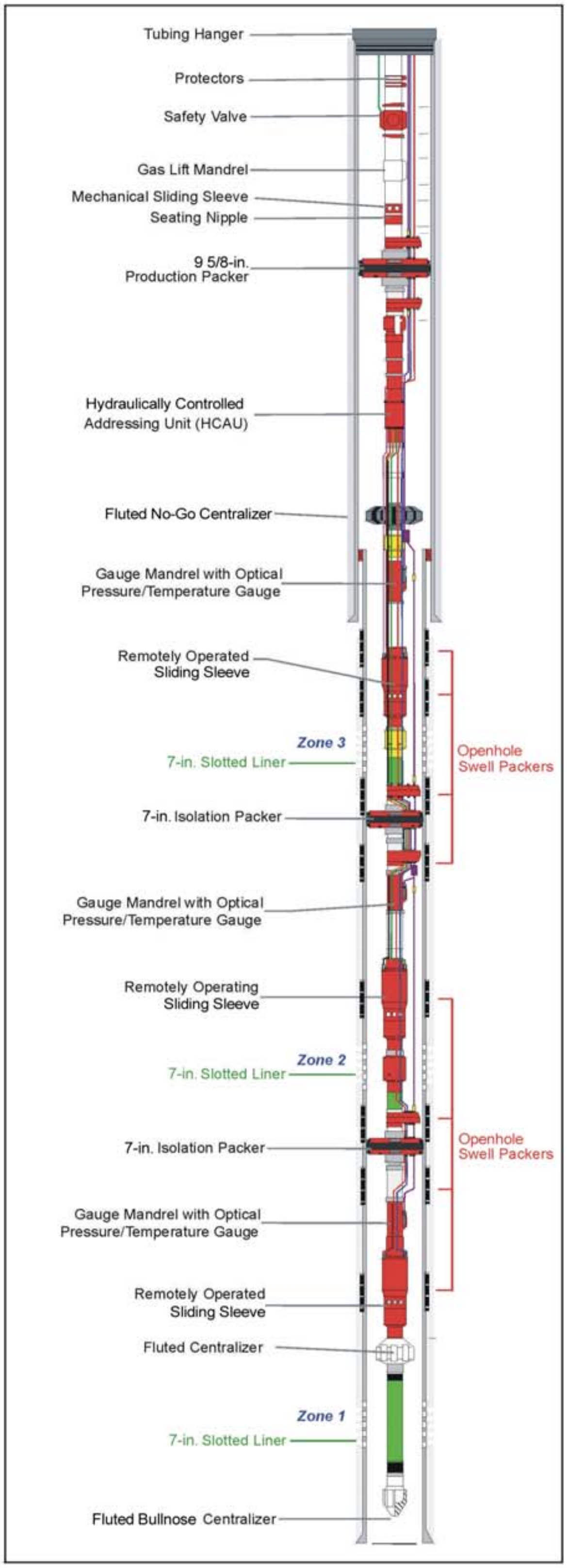

Figure 2. Schematic of the In-well System

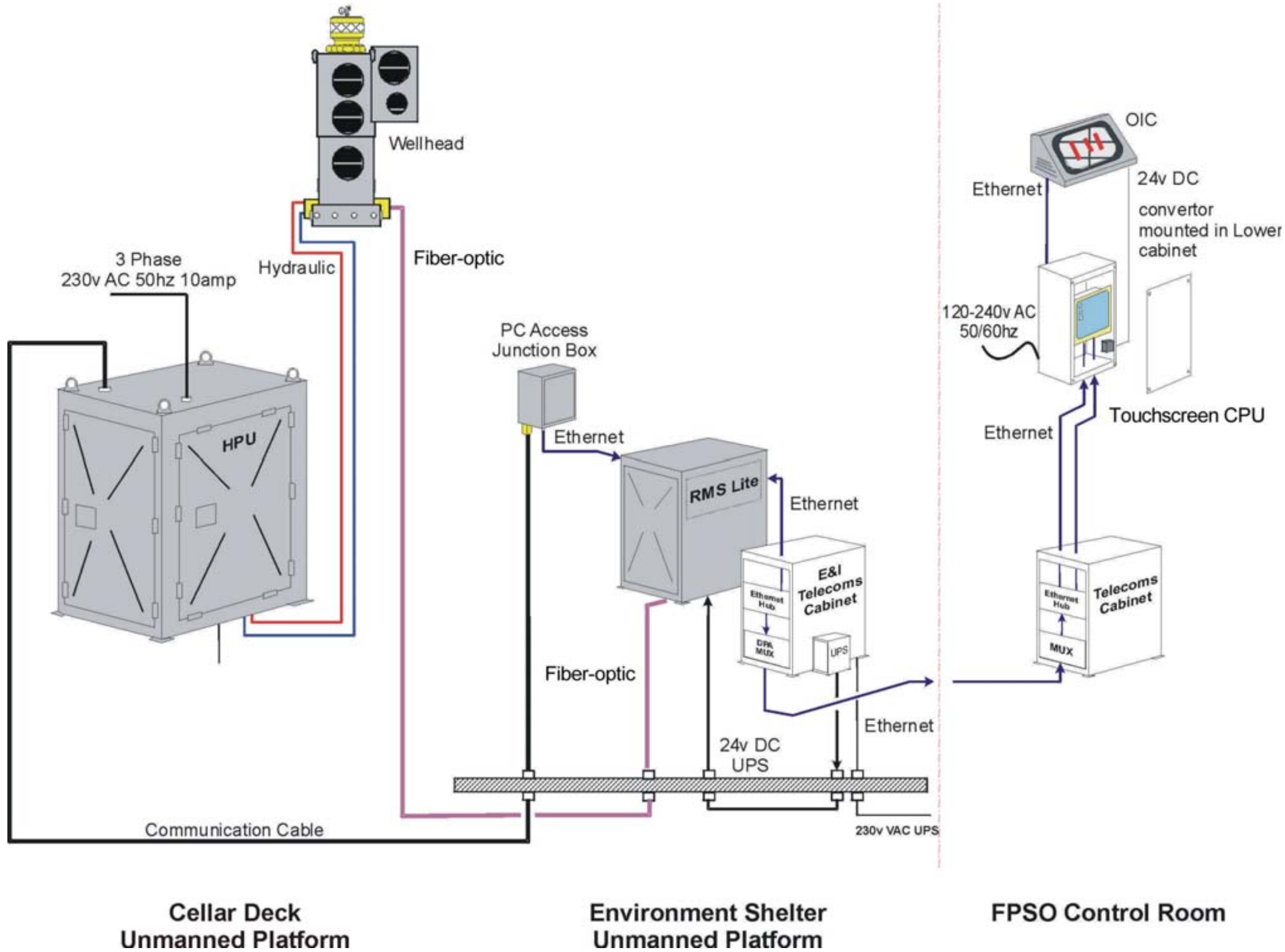

Figure 3. Schematic of the Surface System

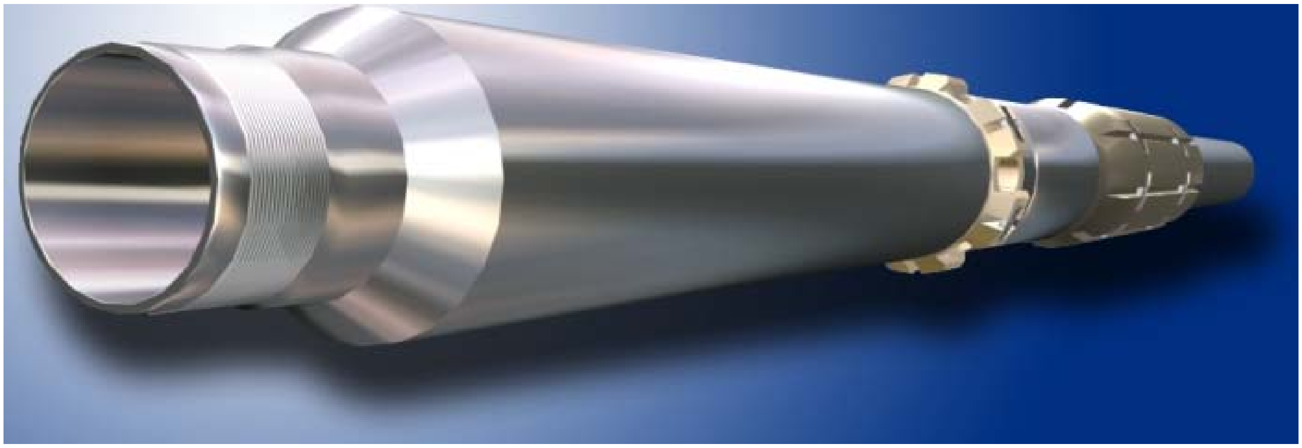

Figure 4. Remotely Operated Sliding Sleeve (ROSS)

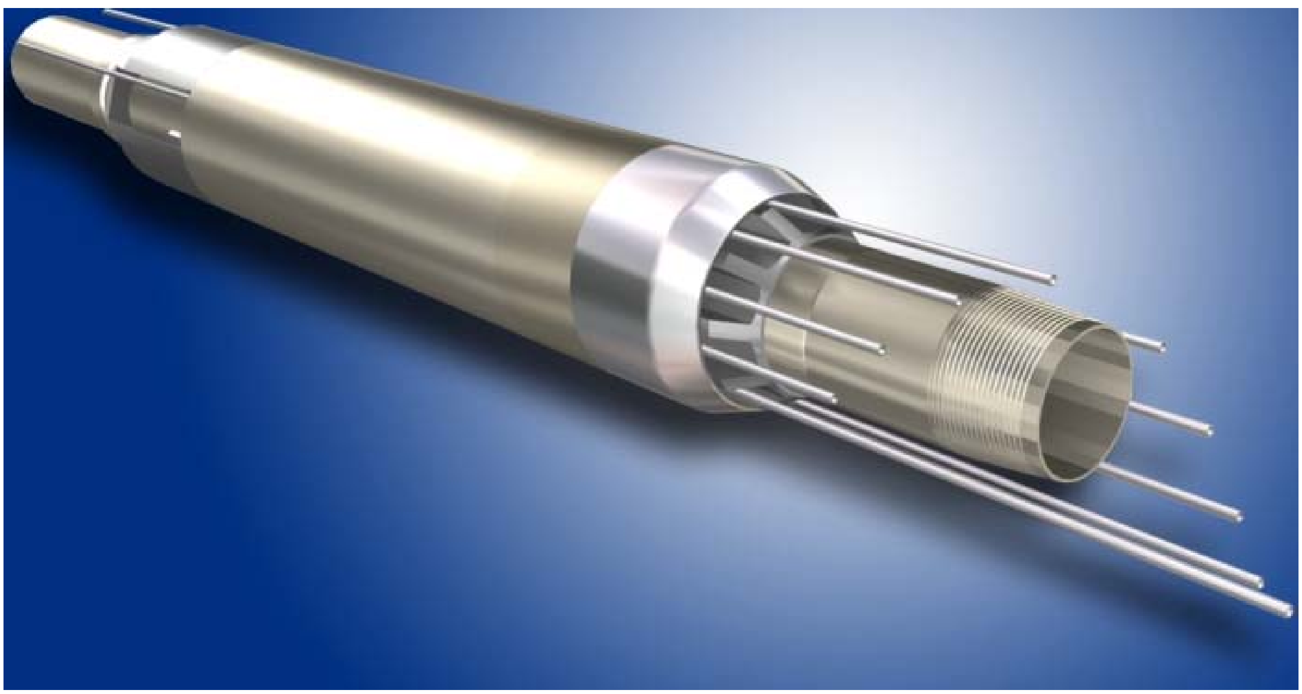

Figure 5. Hydraulically Controlled Addressing Unit (HCAU)

Figure 6. Optical Pressure/temperature Gauge Mounted on Mandrel

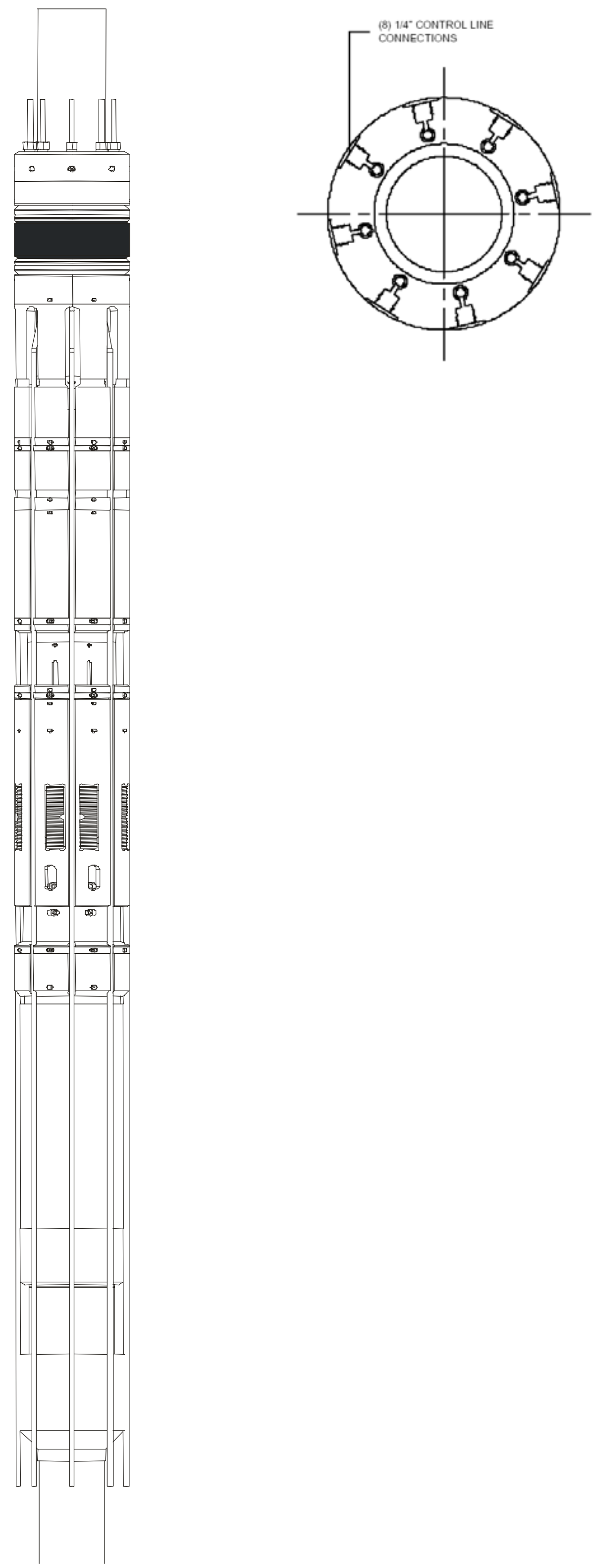

Figure 7. HellCat Production Packer

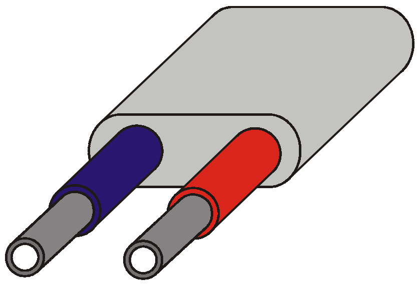

Fig 8: Hydraulic flatpack

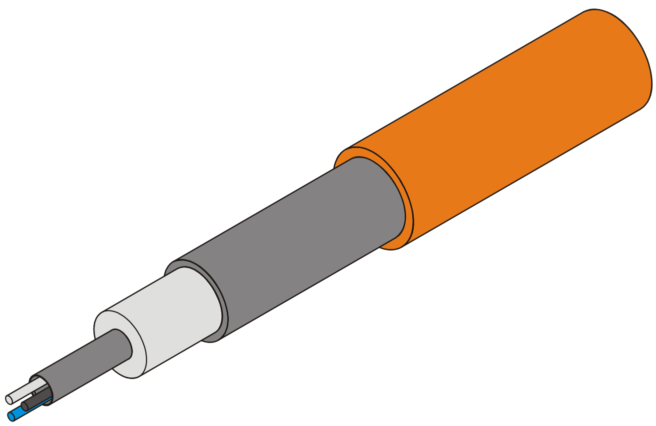

Fig 9: Fibre Optic flatpack

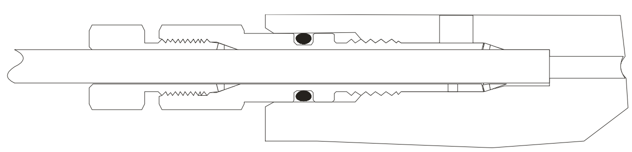

Figure 10. Hydraulic Jam Nut Fitting

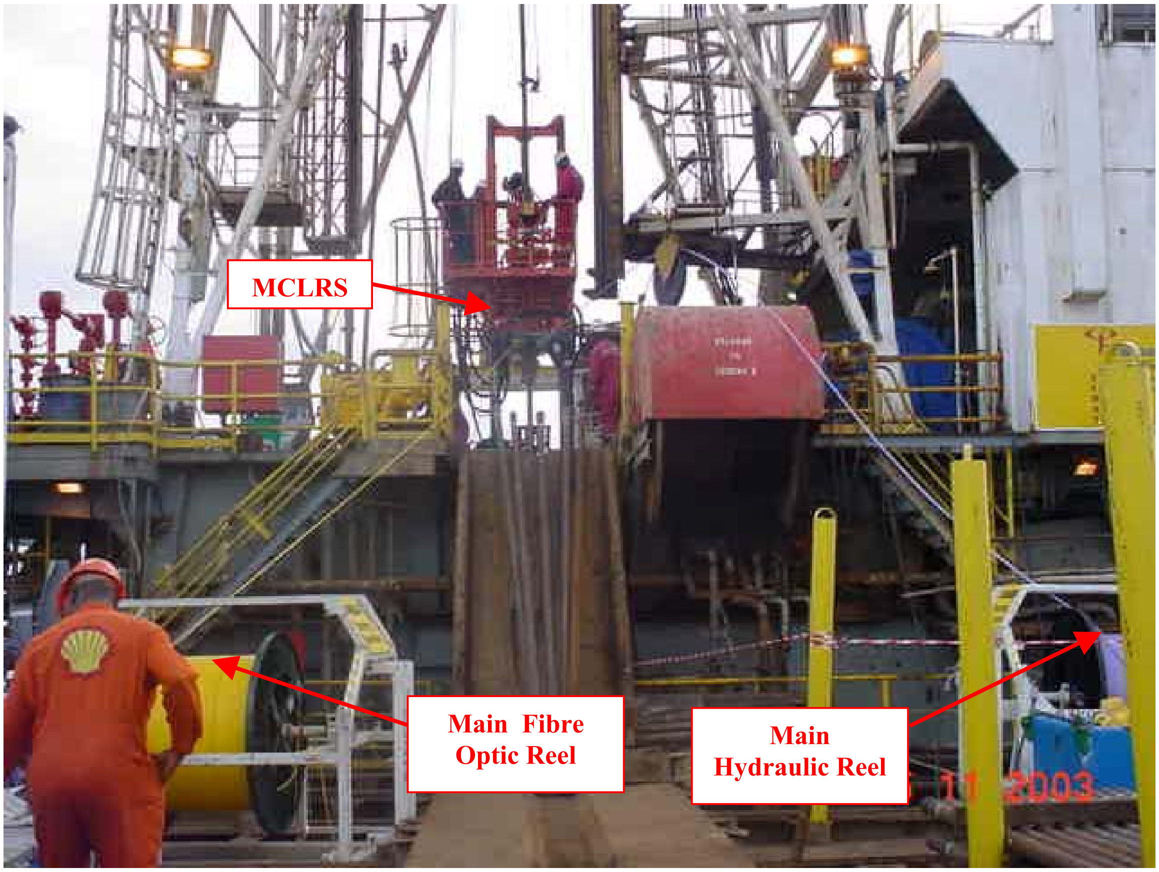

Fig. 11: Installation of the EA-54 Smart Well Completion on Trident-8 rig